

11 November 2024

Trading conduct report 3-9 November 2024

Market monitoring weekly report

Trading conduct report 3-9 November 2024

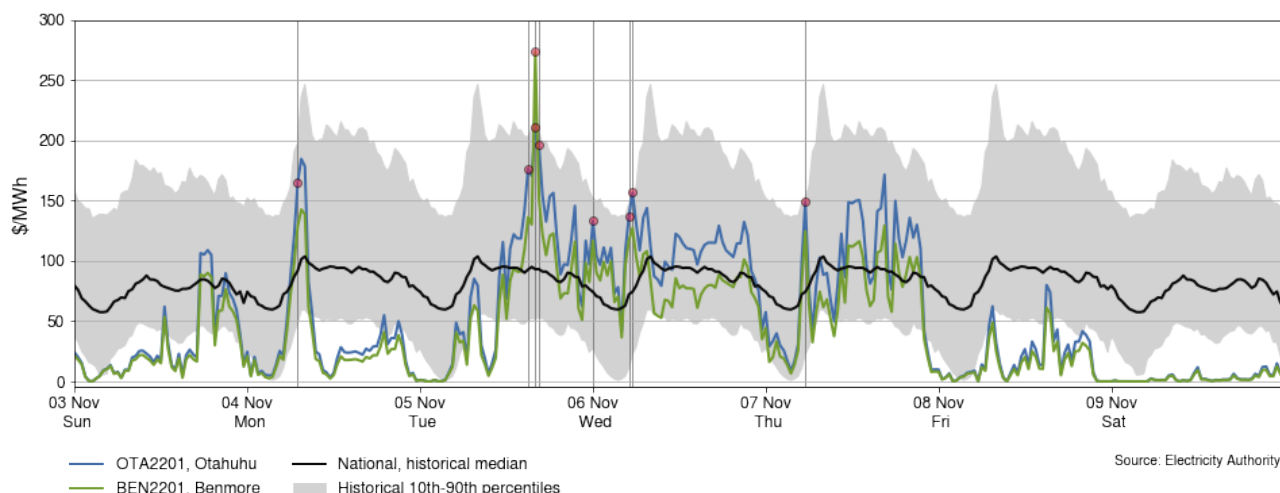
1. Overview

- 1.1. There was an overall increase in spot prices this week although the weekly average price was still under \$50/MWh. Thermal generation reduced (~2% of the weekly generation) with only one Rankine running during the day as baseload most of the week and peaker generation mainly running whilst wind generation was low midweek. Hydro storage steeply increased towards the end of this week with national controlled storage at 125% of historic mean as of 9 November.

2. Spot prices

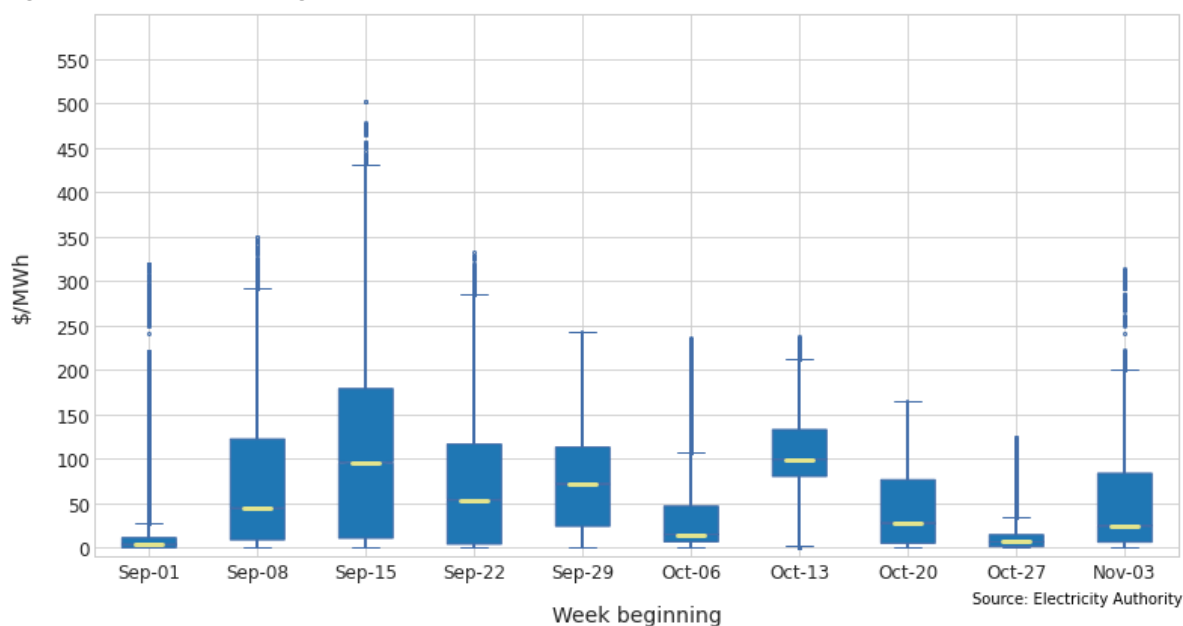
- 2.1. This report monitors underlying wholesale price drivers to assess whether trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Between 3 - 9 November 2024:
 - (a) the average wholesale spot price across all nodes was \$46/MWh
 - (b) 95% of prices fell between \$0.01/MWh and \$147/MWh.
- 2.3. Overall, spot prices were generally close to or below the historic median this week, although midweek prices were often within \$100-150/MWh particularly in the North Island. The weekly average price increased by around \$37/MWh compared to the previous week.
- 2.4. Low temperatures on Monday morning saw high peak demand leading to Ōtāhuhu prices between \$165-\$185/MWh from 7.00am to 8.00am. Benmore prices were over \$100/MWh during this same period but remained below \$150/MWh.
- 2.5. The highest price this week occurred on Tuesday at 4.00pm when the price at Benmore reached \$273/MWh. At the same time the price at Ōtāhuhu was \$210/MWh. There were temporary load management constraints limiting South Island generation during this trading period. There was also a big drop off in wind generation at this time leading to forecasting errors which also likely affected the spot price.
- 2.6. There was also price separation during the day over Wednesday and Thursday where Ōtāhuhu prices were between \$30-\$40/MWh more than Benmore. HVDC flows were high and near northward capacity most of this time, due to very low wind generation.
- 2.7. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than quartile 3 (75th percentile) plus 1.5 times the inter-quartile range of historic prices, plus the difference between this week's median and the historic median, are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 3 - 9 November 2024



- 2.8. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.
- 2.9. There was more variation in prices this week with the middle 50% of prices ranging from \$6/MWh and \$84/MWh. The median price was ~\$25/MWh.

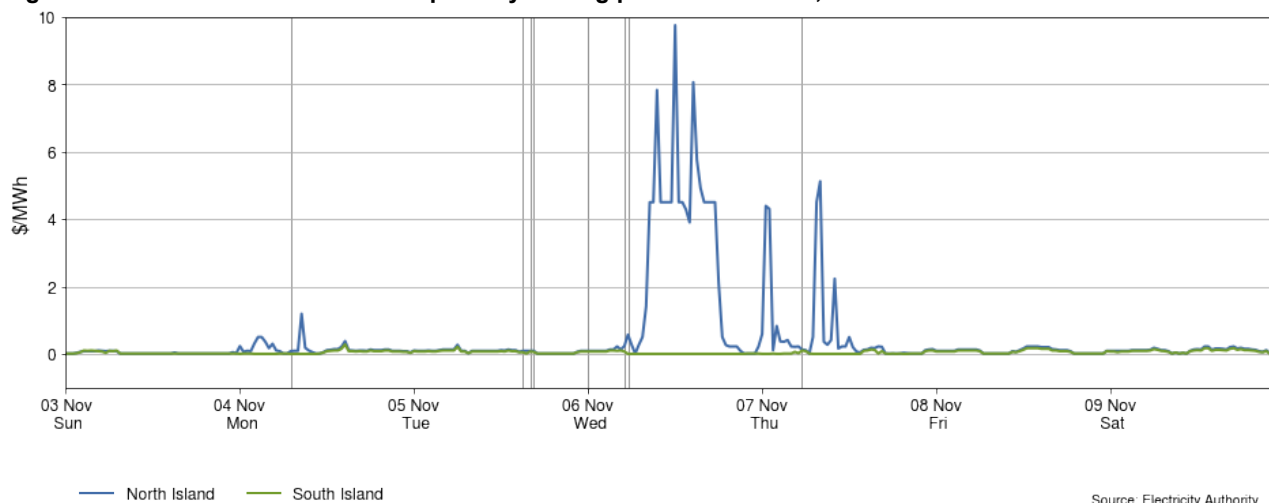
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

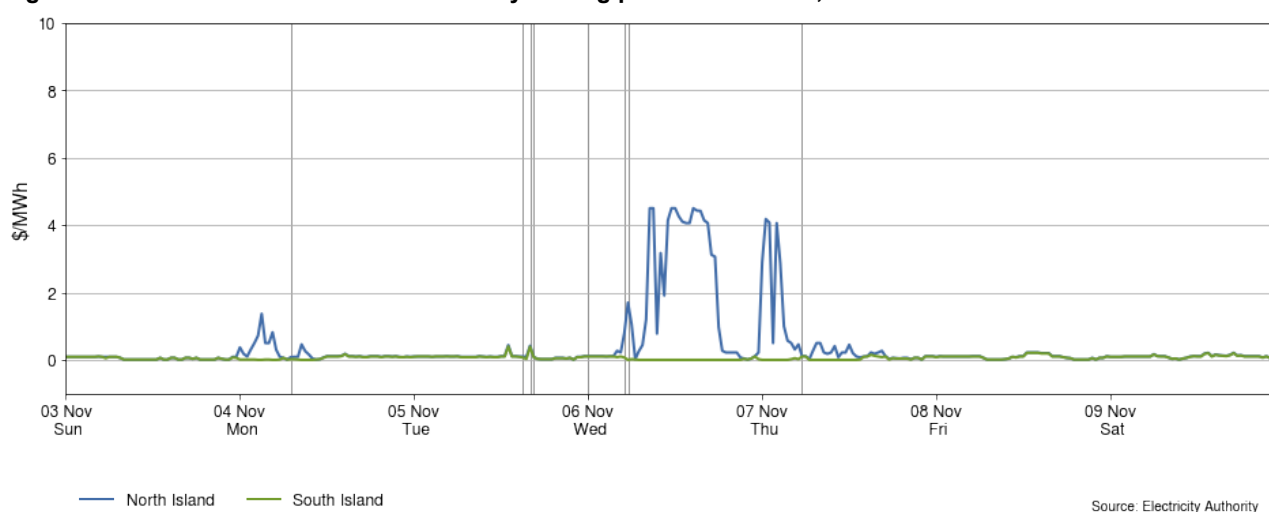
- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR prices were mostly below \$1/MWh. There was some separation with North Island FIR due to the HVDC setting the risk for much of Wednesday and Thursday due to high transfer northwards. North Island FIR prices however remained small and under \$10/MWh.

Figure 3: Fast instantaneous reserve price by trading period and island, 3 - 9 November 2024



3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were low and mostly below \$1/MWh apart from some small price separation on Wednesday and Thursday. As with FIR, this was due to high flows northwards and the HVDC setting the risk. North Island SIR remained low and under \$5/MWh.

Figure 4: Sustained instantaneous reserve by trading period and island, 3 - 9 November 2024

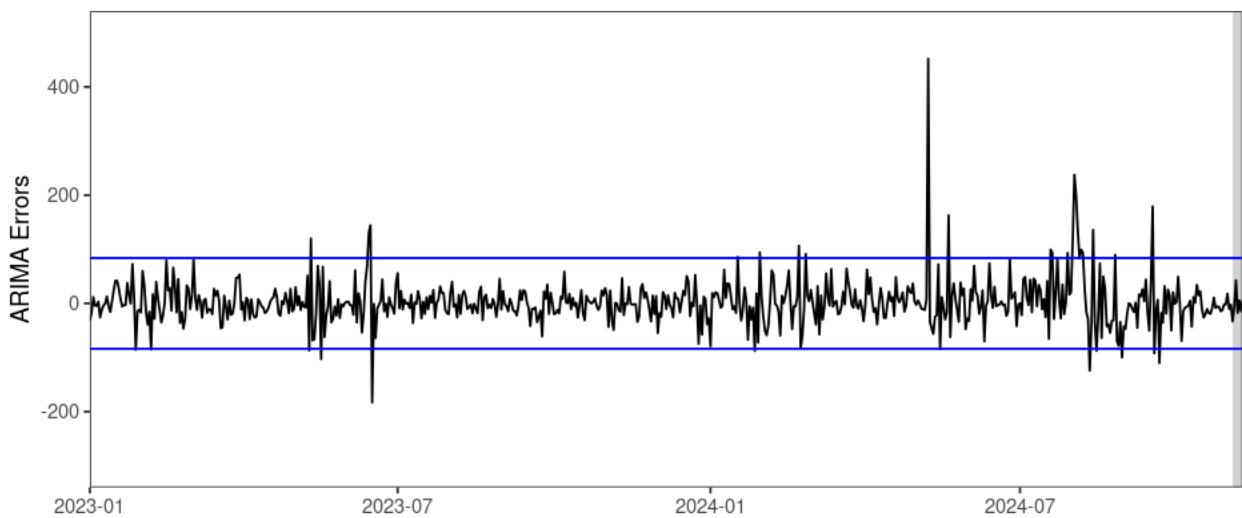


4. Regression residuals

- 4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in [Appendix A](#).
- 4.2. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the actual average daily price and vice versa. When residuals are small this indicates that average daily prices are likely largely aligned with market conditions. These small deviations reflect market variations that may not be controlled in the regression analysis.

- 4.3. This week all residuals were small and within two standard deviation of the data meaning prices were close to what the model expected.

Figure 5: Residual plot of estimated daily average spot prices, 1 January 2023 - 2 November 2024

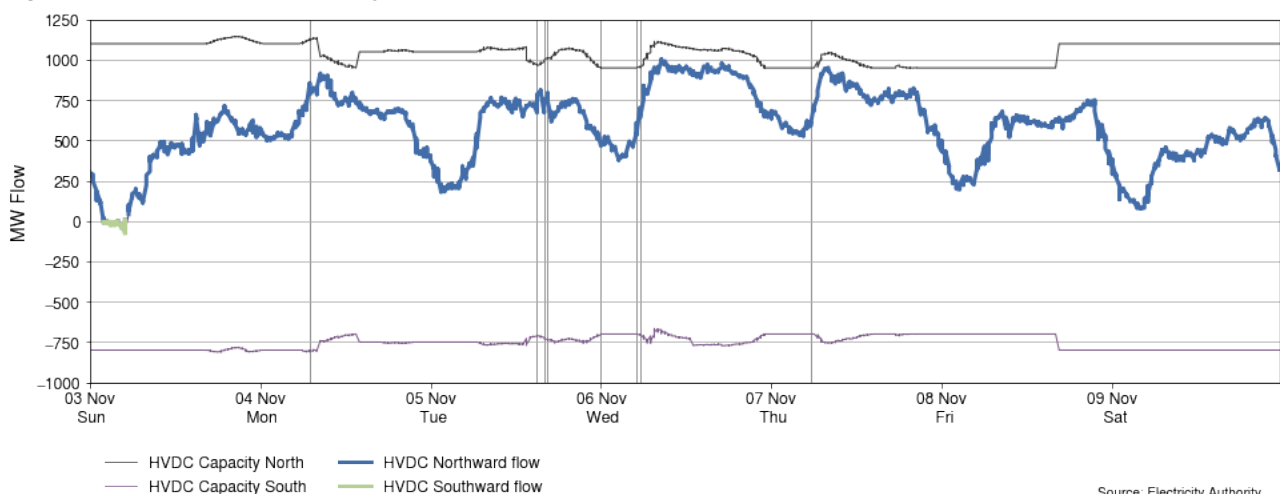


Source: Electricity Authority/Appendix A

5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 3 - 9 November 2024. HVDC flows were mainly northwards and at times close to capacity, particularly on days where wind generation was low. The days this week with the highest overall prices occurred when northward HVDC transfers were high as North Island wind generation was low.

Figure 6: HVDC flow and capacity, 3 - 9 November 2024

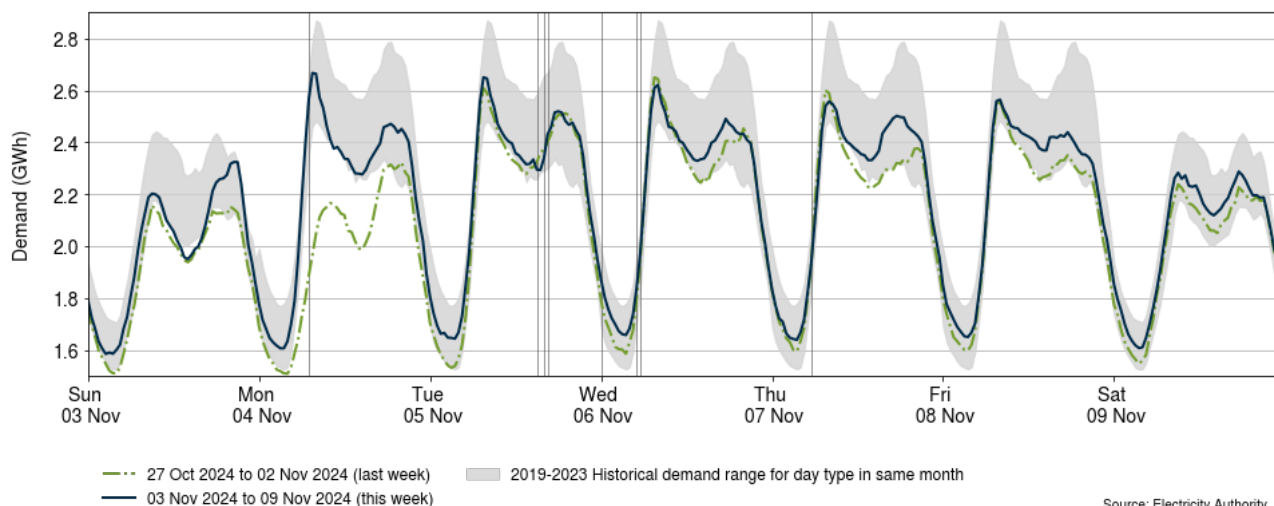


Source: Electricity Authority

6. Demand

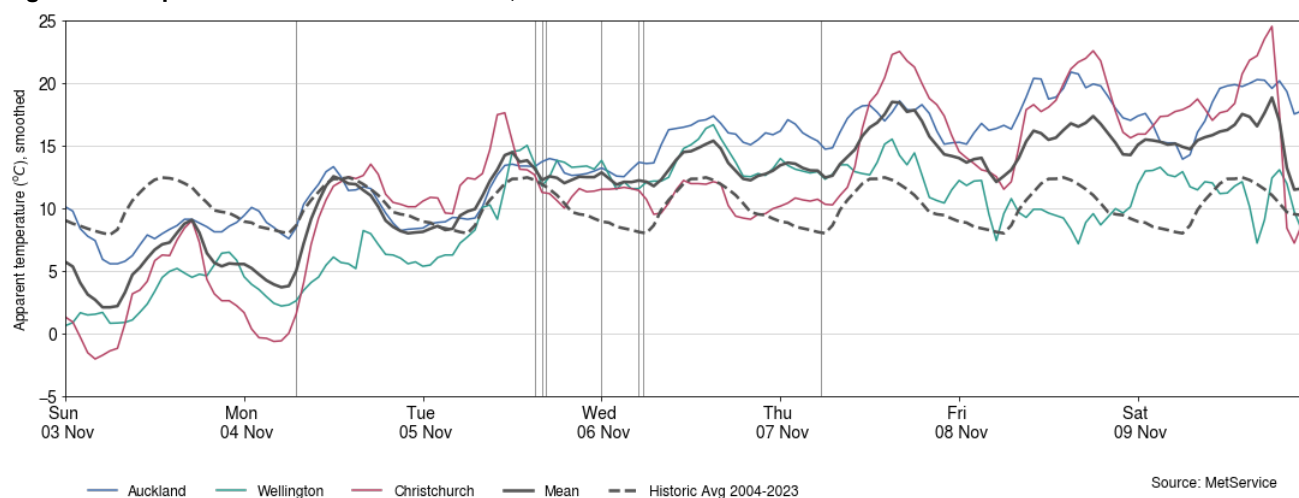
- 6.1. Figure 7 shows national demand between 3 - 9 November 2024, compared to the historic range and the demand of the previous week. Morning peak demand was above 2.6GWh at the start of the working week with the highest trading period demand occurring on Monday at 7.30am.

Figure 7: National demand, 3 - 9 November 2024 compared to the previous week



- 6.2. Apparent temperatures were below average at the start of the week, particularly on Monday morning when we saw the high peak demand. Temperatures increased during the week to be above average by the weekend. Apparent temperatures ranged from ranging from 5°C to 22°C in Auckland, 0.6°C to 17°C in Wellington, and -2°C to 24°C in Christchurch.
- 6.3. Figure 8 shows the hourly apparent temperature at main population centres from 3 - 9 November 2024. The apparent temperature is an adjustment of the recorded temperature that accounts for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean temperature of the main population centres, and the mean historical apparent temperature of similar weeks, from previous years, averaged across the three main population centres.
- 6.4. Apparent temperatures were below average at the start of the week, particularly on Monday morning when we saw the high peak demand. Temperatures increased during the week to be above average by the weekend. Apparent temperatures ranged from ranging from 5°C to 22°C in Auckland, 0.6°C to 17°C in Wellington, and -2°C to 24°C in Christchurch.

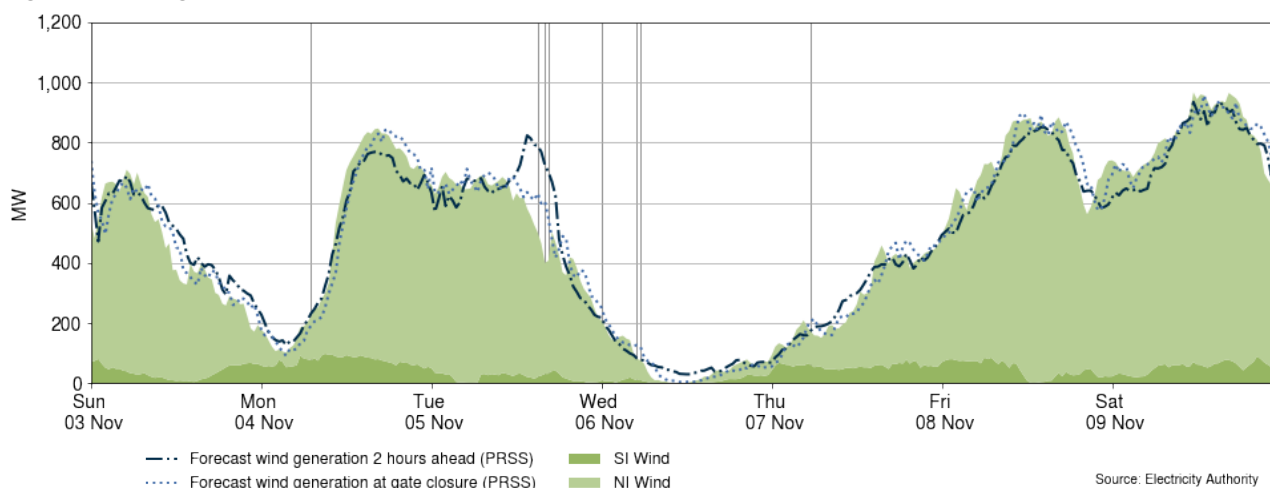
Figure 8: Temperatures across main centres, 3 - 9 November 2024



7. Generation

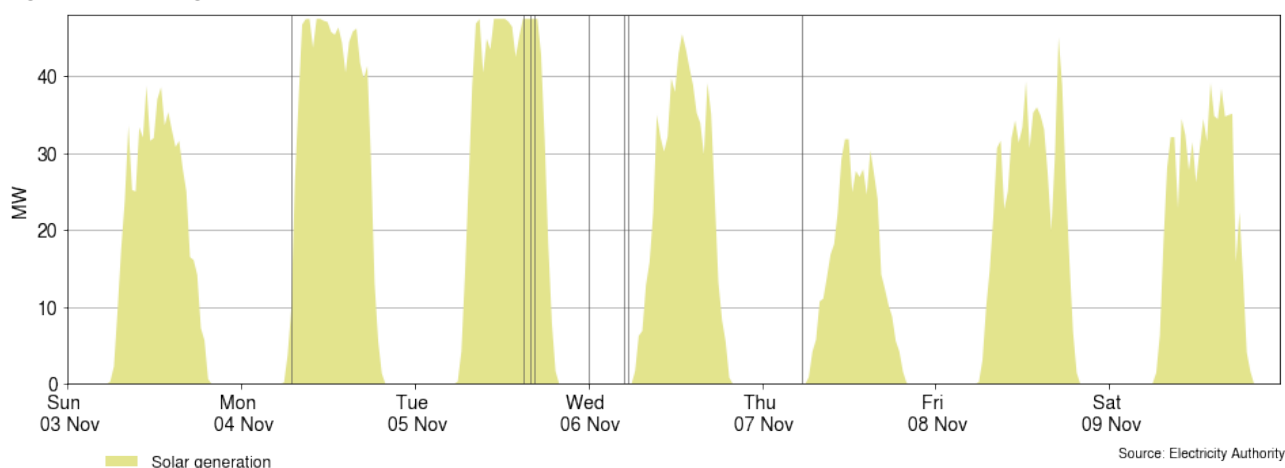
- 7.1. Figure 9 shows wind generation and forecast from 3 - 9 November 2024. This week wind generation varied between 2MW and 966MW. Gate closure forecast was ~200MW higher than actual generation on Tuesday at 4.00pm. This was the same trading period where prices went above \$200/MWh.
- 7.2. Daily average wind between Sunday and Tuesday was within ~448-547MW, with Saturday seeing the highest daily average wind at ~816MW. Wind generation was lowest on Wednesday when the daily average generation was ~61MW. Spot prices were highest on Wednesday and Thursday when overall wind generation was mostly below 400MW.

Figure 9: Wind generation and forecast, 3 - 9 November 2024



- 7.3. Figure 10 shows solar generation from 3 - 9 November 2024. Solar generation on Monday and Tuesday was over 40MW most of the day. Most other days saw a maximum trading period average over 30MW.

Figure 10: Solar generation, 3 - 9 November 2024



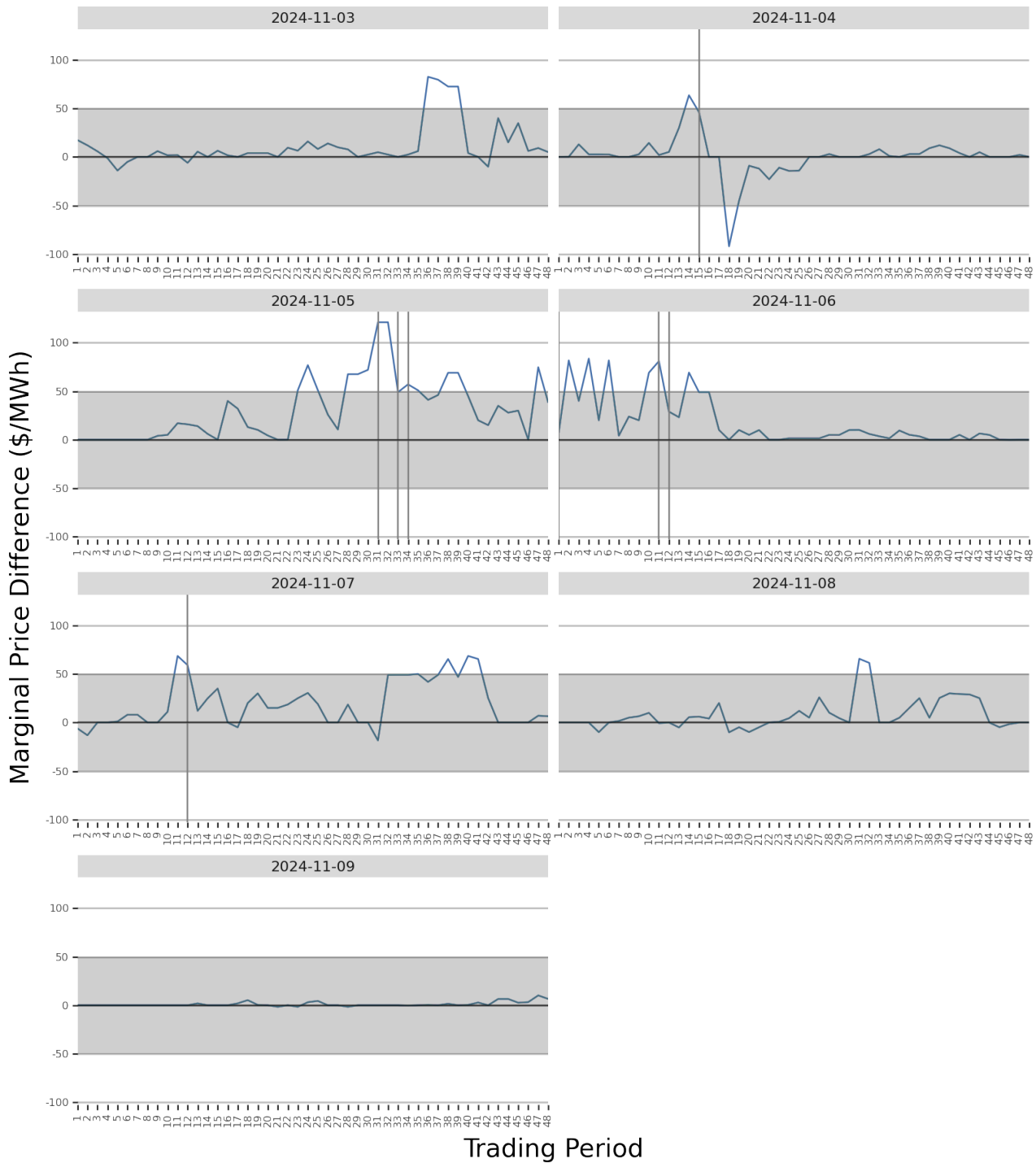
- 7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS¹) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being

¹ Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can signal that forecasting inaccuracies had a large impact on the final price for that trading period.

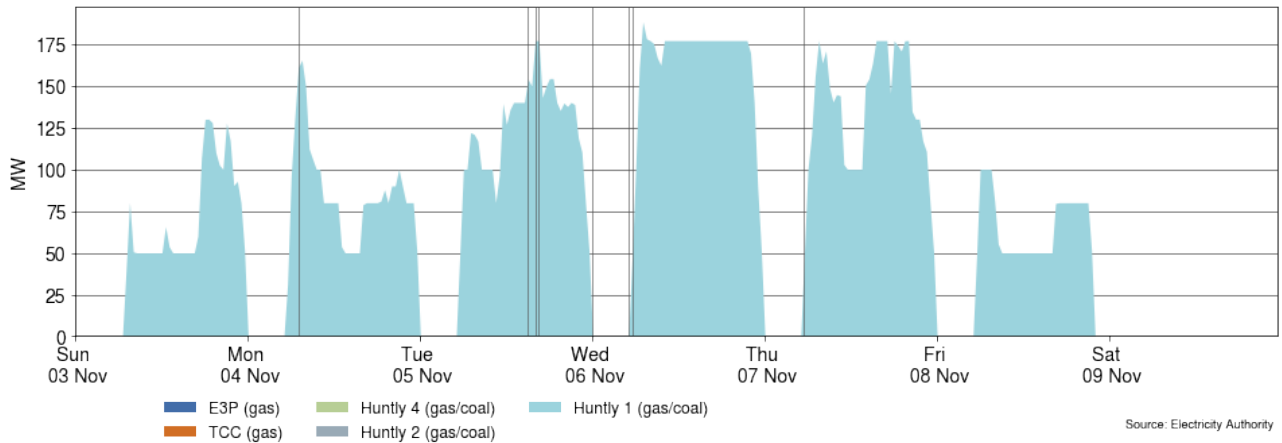
- 7.5. The largest difference this week was on Tuesday afternoon between 3.00pm - 4.30pm. Wind forecasting at gate closure was over 100MW over forecast and demand was higher than forecast from between ~80-125MW for a few of these trading periods.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 3 - 9 November 2024



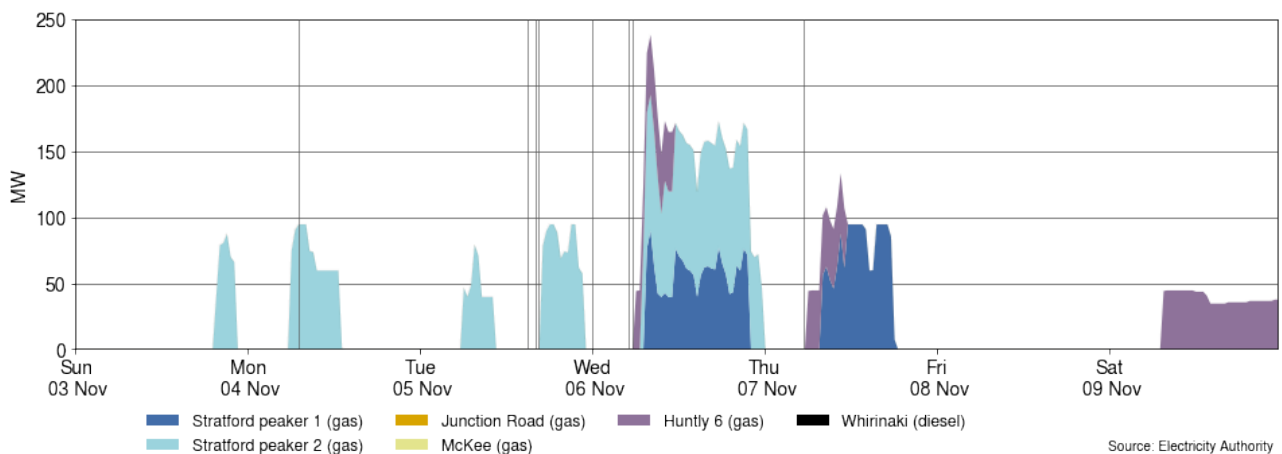
7.6. Figure 12 shows the generation of thermal baseload between 3 - 9 November 2024. Huntly 1 ran as baseload generation each day (apart from Saturday) from just before morning peak until around midnight.

Figure 12: Thermal baseload generation, 3 - 9 November 2024



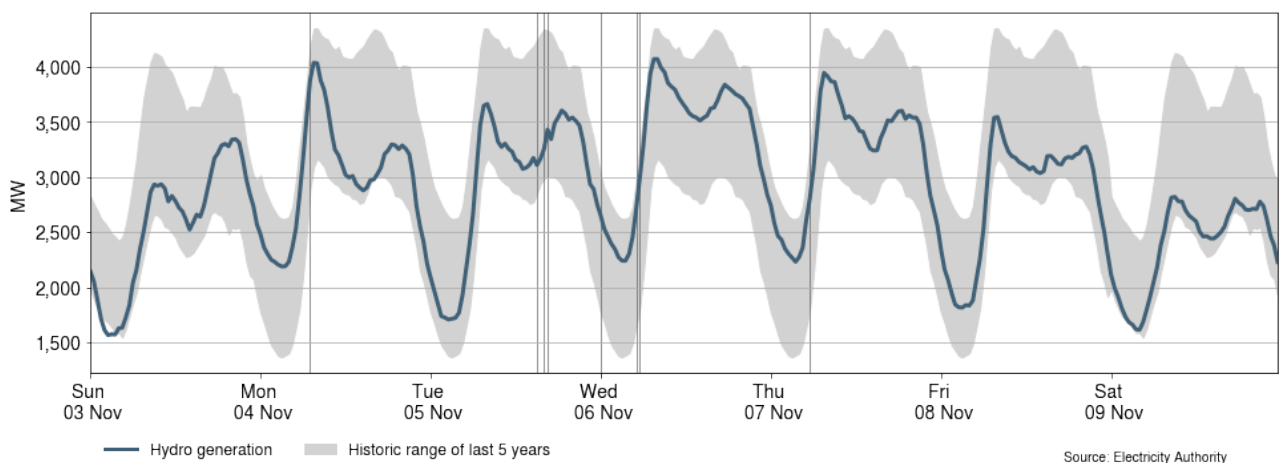
7.7. Figure 13 shows the generation of thermal peaker plants between 3 - 9 November 2024. The Stratford units and Huntly 6 were the only peaker plants to run this week. Most generation from the three units came on Wednesday when there was little wind generation during the day.

Figure 13: Thermal peaker generation, 3 - 9 November 2024



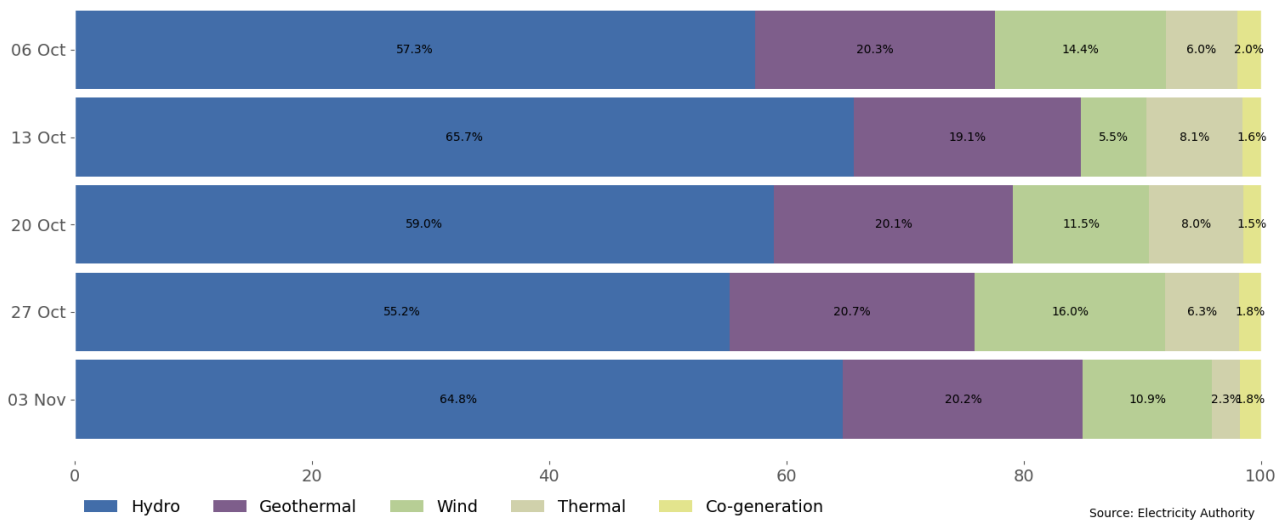
7.8. Figure 14 shows hydro generation between 3 - 9 November 2024. Monday morning peak and midweek when wind generation was low, saw hydro generation nearer the upper end of the historic average for this time of year.

Figure 14: Hydro generation, 3 - 9 November 2024



- 7.9. As a percentage of total generation, between 3 - 9 November 2024, total weekly hydro generation was 64.8%, geothermal 20.2%, wind 10.9%, thermal 2.3%, and co-generation 1.8%, as shown in Figure 15. Less wind and thermal generation this week saw an increase to the proportion of generation from hydro.

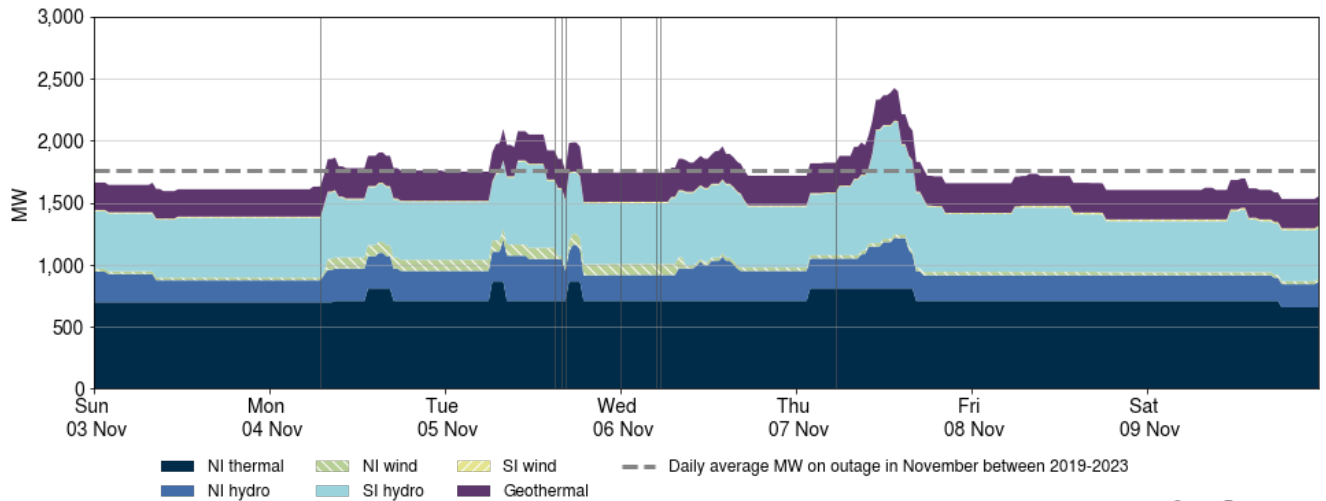
Figure 15: Total generation by type as a percentage each week, 6 October to 3 November



8. Outages

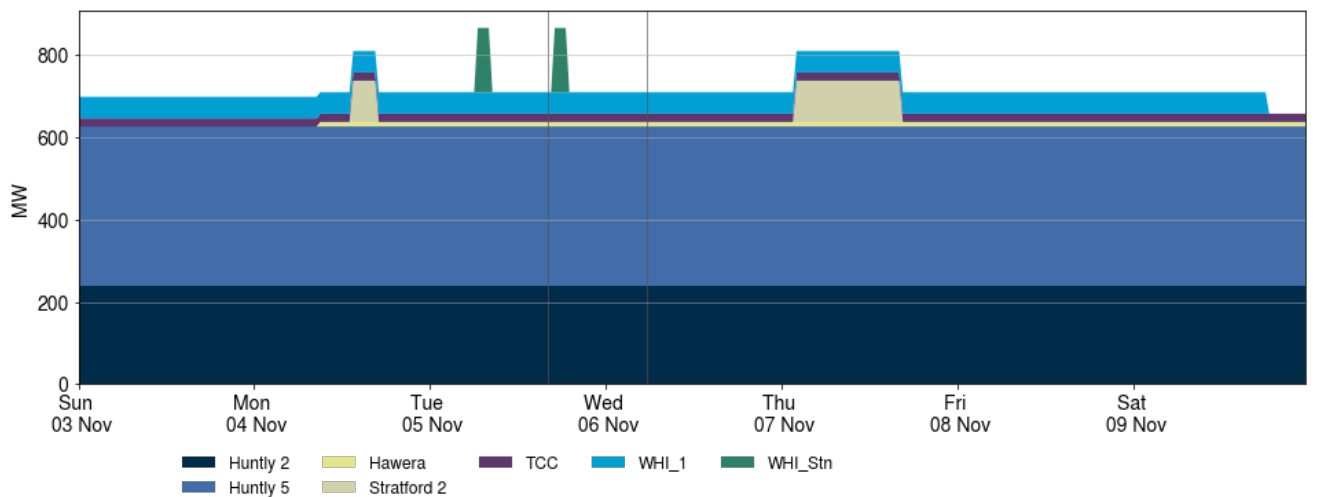
- 8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 3 - 9 November 2024 ranged between ~1500MW and ~2400MW. Figure 17 shows the thermal generation capacity outages.
- 8.2. Notable outages include:
- (a) Huntly 5 is on outage until 29 November
 - (b) Huntly 2 is on outage until March 2025
 - (c) Tauhara geothermal is on outage until 13 November
 - (d) Whirinaki station had short outages on 5 November morning and evening
 - (e) Stratford 2 was on outage in the afternoon on 7 November
 - (f) Te Uku wind farm had outages over 4-6 November
 - (g) Various North and South Island hydro units are on outage.

Figure 16: Total MW loss from generation outages, 3 - 9 November 2024



Source: Transpower

Figure 17: Total MW loss from thermal outages, 3 - 9 November 2024

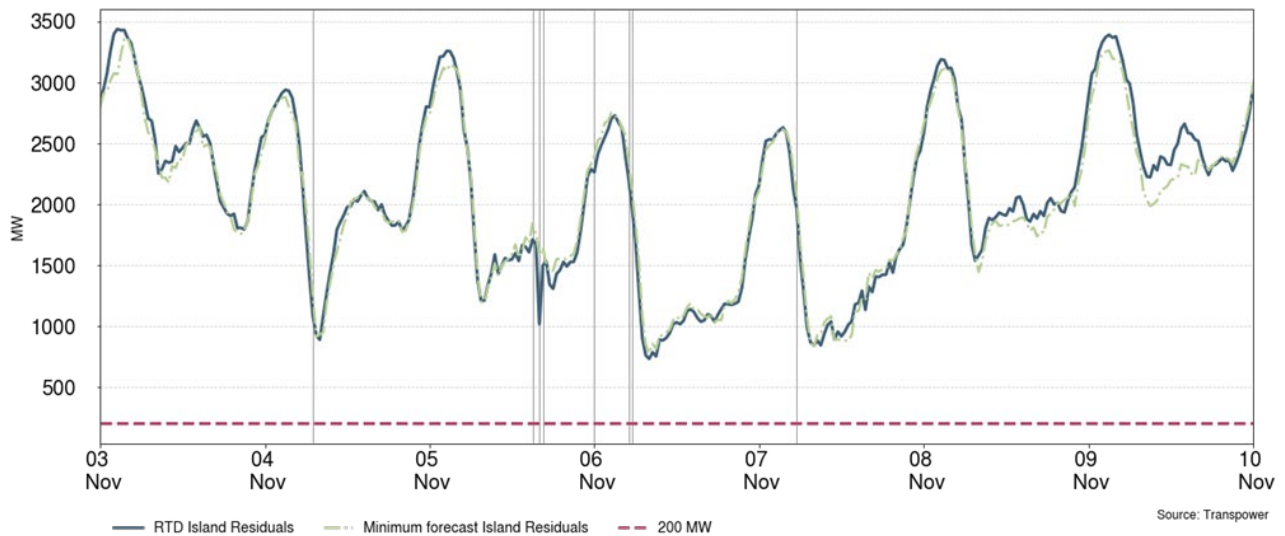


Source: Transpower

9. Generation balance residuals

- 9.1. Figure 18 shows the national generation balance residuals between 3 - 9 November 2024. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals, and the blue line represents the real-time dispatch (RTD) residuals.
- 9.2. Generation balance residuals continue to be healthy with the minimum residual generation of ~732MW on 6 November at 8.00am.

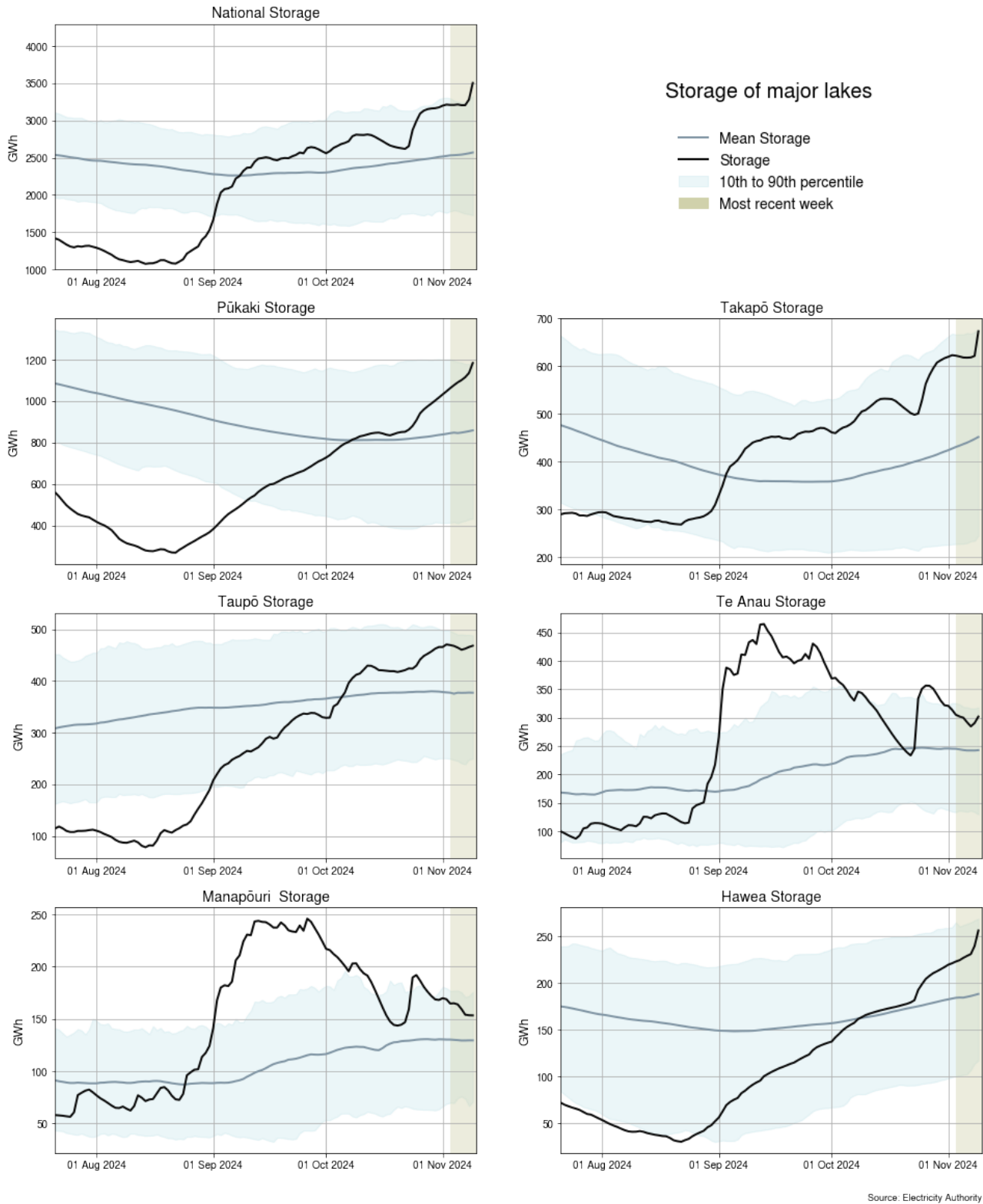
Figure 18: National generation balance residuals, 3 - 9 November 2024



10. Storage/fuel supply

- 10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.
- 10.2. National controlled storage continued to increase over the last week. As of 9 November, controlled storage was 81.3% nominally full and ~125% of the historical average for this time of the year.
- 10.3. Taupō storage was relatively stable with only a small increase in the latter half on the week. It remains close to its 90th percentile region. Both Pūkaki and Takapō showed a steep increase to storage with both lakes now around their 90th percentile region.
- 10.4. Hawea showed a steep increase in storage in the second half of the week and is approaching its historic 90th percentile region. Overall storage has decreased in both Manapōuri and Te Anau, although there was a small uptick towards the end of the week at Te Anau.

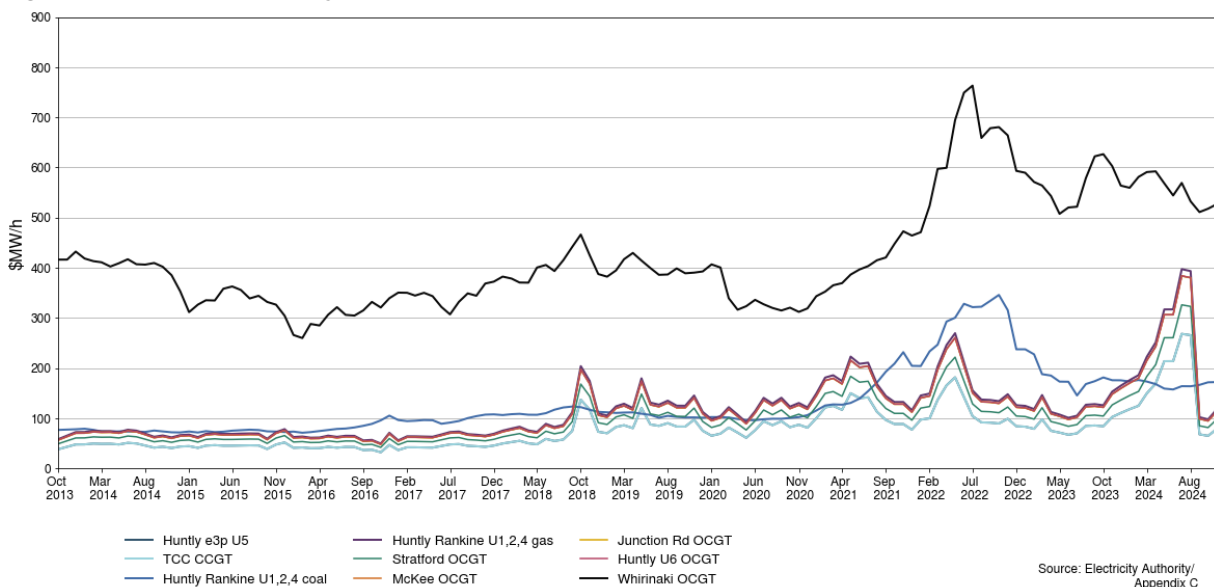
Figure 19: Hydro storage



11. Prices versus estimated costs

- 11.1. In a competitive market, prices should be close to (but not necessarily at) the short-run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).
- 11.2. The SRMC (excluding opportunity cost of storage) for thermal fuels is estimated using gas and coal prices, and the average heat rates for each thermal unit. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.
- 11.3. Figure 20 shows an estimate of thermal SRMCs as a monthly average up to 1 November. The SRMC for gas is similar to the previous month with only a small increase. Coal and diesel SRMC have also increased since the previous month.
- 11.4. The latest SRMC of coal-fuelled Rankine generation is ~\$172/MWh with the cost of running the Rankines on gas remains lower at ~\$118/MWh.
- 11.5. The SRMC of gas fuelled thermal plants is currently between \$79/MWh and \$118/MWh.
- 11.6. The SRMC of Whirinaki is ~\$527/MWh.
- 11.7. More information on how the SRMC of thermal plants is calculated can be found in [Appendix C](#).

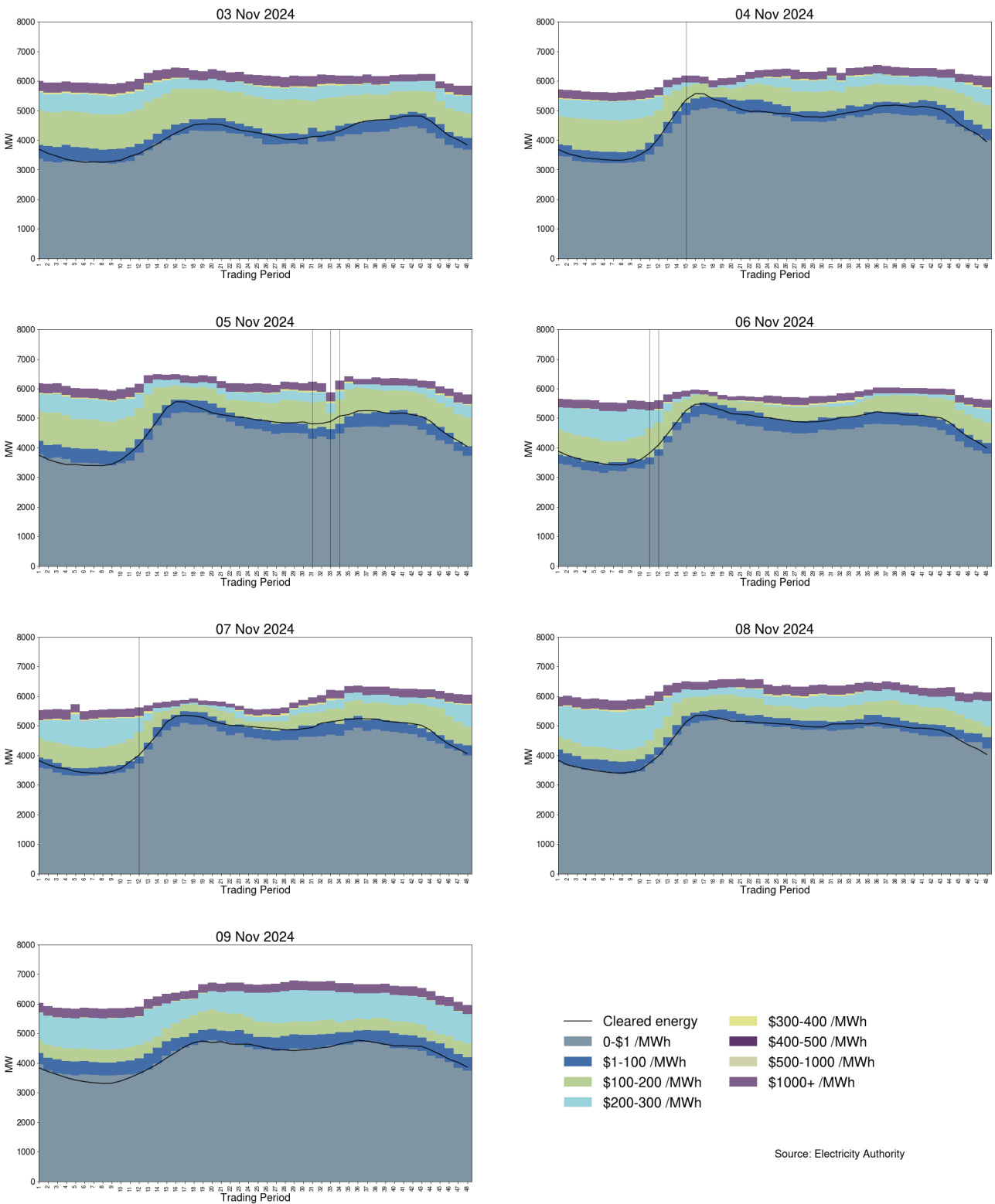
Figure 20: Estimated monthly SRMC for thermal fuels



12. Offer behaviour

- 12.1. Figure 21 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price.
- 12.2. Offers mainly cleared in the \$1-\$100/MWh region this week. However, there were periods, mainly when demand was high and/or wind generation was low, where offers were clearing between \$100-\$200/MWh.

Figure 21: Daily offer stacks



13. Ongoing work in trading conduct

13.1. This week prices generally appeared to be consistent with supply and demand conditions.

13.2. Further analysis is being done on the trading periods in Table 1 as indicated.

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance for advice	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance for advice	Contact	Multiple	High hydro offers
1/07/2024-23/08/2024	Several	These trading periods are now part of a s16 review	N/A	N/A	High energy prices
3-4/09/2024 and 13-18/09/2024	Several	Further analysis	Contact Energy	Clutha scheme	Hydro offers